NORTHERN STATES POWER COMPANY **ISSUE DATE: AUGUST 23, 1988**
DOCKET NO: E-002/GR-87-670

FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

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BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Barbara Beerhalter	Chair
Cynthia A. Kitlinski	Commissioner
Norma McKanna	Commissioner
Robert J. O'Keefe	Commissioner
Darrel L. Peterson	Commissioner

In the Matter of the Application of Northern States Power Company for Authority to Increase its Rates for Electric Service in Minnesota

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FINDINGS OF FACT, CONCLUSIONS OF LAW, AND ORDER

PROCEDURAL HISTORY

On November 2, 1987 Northern States Power Company (NSP or the Company) filed a petition for authorization to increase its electric rates. The Company requested an annual rate increase of approximately $99.3 million. The Company subsequently reduced this request to $97.3 million.

On December 4, 1987 the Commission accepted the filing, suspended the proposed rates, and ordered contested case proceedings under Minn. Stat. Section 216B.16, subd. 1 (1986). The Office of Administrative Hearings assigned Administrative Law Judge Richard C. Luis to the case.

On December 21, 1987 the Commission issued its ORDER SUPPLEMENTING NOTICE AND ORDER FOR HEARING OF DECEMBER 4, 1987. That Order instructed all parties to address the appropriateness of phasing in to rate base the Company's new Sherco 3 facility.

On December 29, 1987 the Commission set interim rates under Minn. Stat. Section 216B.16, subd. 3 (1986). Interim rates were authorized as of January 1, 1988 and were set at a level allowing an additional $94,980,000 in annual revenues.

The Administrative Law Judge (ALJ) held a Prehearing Conference on December 30, 1987. There the parties and the ALJ identified the major issues, established procedural guidelines, and set timetables.

I. INTERVENORS

The following parties filed petitions to intervene in the case. The ALJ granted all petitions, making them parties to the proceeding.

Minnesota Department of Public Service
Residential Utilities Division of the Office of the Attorney General
City of St. Paul and the Board of Water Commissioners of the City of St. Paul
Suburban Rate Authority
District Heating Development Company, d/b/a District Energy St. Paul, Inc.
Union Carbide Corporation
Champion International Corporation
Metalcasters of Minnesota
National Solid Waste Management Association
Metropolitan Senior Federation
Minnesota Public Interest Research Group
North American Water Office
St. Paul Area Chamber of Commerce

The National Solid Waste Management Association subsequently withdrew its petition to intervene. Union Carbide Corporation made no appearance at the evidentiary hearings, despite its party status.

II. PUBLIC HEARINGS

The ALJ held public hearings to receive comments and questions from non-intervening ratepayers at the following times and places. The first number on each line is the number of people who attended the hearing. The second number is the number of people who spoke.

March 14, 1988	Bloomington	20	3
March 15, 1988	Winona	19	3
March 16, 1988	Mankato	19	2
March 17, 1988 (afternoon)	Minneapolis	37	7
March 17, 1988 (evening)	Brooklyn Park	17	1
March 21, 1988 (afternoon)	St. Paul	25	5
March 21, 1988 (evening)	St. Paul	19	3
March 22, 1988	Pipestone	13	2
March 23, 1988	St. Cloud	21	3

Commissioner Peterson attended the hearings in Bloomington and Mankato. Commissioner McKanna attended the hearing in Winona and the evening hearing in St. Paul. Commissioner Kitlinski attended the hearings in Minneapolis, Brooklyn Park, and the afternoon hearing in St. Paul. Commission staff attended all hearings except the one in Pipestone.

The Residential Utilities Division of the Office of the Attorney General attended all metropolitan area hearings, and the Department of Public Service attended all public hearings. The Company attended all hearings as well.

III. EVIDENTIARY HEARINGS

The ALJ held evidentiary hearings in St. Paul April 5-8, 1988, and April 11-12, 1988. Appearances at the evidentiary hearings were as follows:

David A. Lawrence and David M. Sparby, Northern States Power Company, 414 Nicollet Mall, Minneapolis, Minnesota 55401, for the Company;

Gregory D. Dittrich, Special Assistant Attorney General, and Richard Lancaster, Lee Larson, Janet F. Gonzalez, Diane Sorrells, John Lindell, and David Jacobson, 780 American Center Building, 150 East Kellogg Boulevard, St. Paul, Minnesota 55101, for Commission Staff;

Michael J. Bradley, Assistant Attorney General, 340 Bremer Tower, Seventh Place and Minnesota Street, St. Paul, Minnesota 55101, for the Residential Utilities Division of the Office of the Attorney General (RUD-OAG);

Ann M. Seha, Special Assistant Attorney General, 200 Lafayette Park Building, 520 Lafayette Road, St. Paul, Minnesota 55155; Joan C. Peterson and Mary Jo Murray, Special Assistant Attorneys General, 1100 Bremer Tower, 7th Place and Minnesota Street, St. Paul, Minnesota 55101, for the Department of Public Service (DPS);

Thomas J. Weyandt, Assistant City Attorney, 647 City Hall, St. Paul, Minnesota 55102, for the City of St. Paul and the St. Paul Board of Water Commissioners (St. Paul);

William E. Flynn and David Sasseville, Lindquist & Vennum, 4200 IDS Center, 80 South Eighth Street, Minneapolis, Minnesota 55402-2205, for the St. Paul Area Chamber of Commerce (Chamber);

Glenn E. Purdue, LeFevere, Lefler, Kennedy, O'Brien and Drawz, 2200 First Bank Place West, Minneapolis, Minnesota 55402, for the Suburban Rate Authority (SRA);

William Mahlum and Christina Stalker, 2222 North Central Life Tower, St. Paul, Minnesota 55101, for District Heating Development Company, d/b/a District Energy of St. Paul (District Heating);

Peggy Wells Dobbins, 915 Aduana Avenue, Coral Gables, Florida 33146, for Champion International (Champion);

Byron E. Starns, Leonard, Street & Deinard, 100 South Fifth Street, Suite 1500, Minneapolis, Minnesota 55402, for the Metalcasters of Minnesota (Metalcasters);

Elmer W. Scott, 190 Iris Park Place, 1885 University Avenue West, St. Paul, Minnesota 55104, for the Metropolitan Senior Federation (MSF);

Scott Wilensky, 2512 Delaware Street Southeast, Minneapolis, Minnesota 55414, for the Minnesota Public Interest Research Group (MPIRG);

George W. Crocker, 1519A East Franklin Avenue, Minneapolis, Minnesota 55404, for the North American Water Office (NAWO);

IV. THE REVENUE REQUIREMENTS STIPULATION

On March 3 NSP, DPS, RUD-OAG, MPIRG, and MSF submitted a stipulation reflecting agreement on all but two of the financial issues. The remaining issues related to the appropriate treatment of certain expenditures in the Company's Conservation Improvement Program Deferred Debit Account.

V. THE OFFER OF SETTLEMENT ON RATE DESIGN

On or about March 31, all parties to this proceeding entered into a stipulated settlement of most of the rate design issues in the case. The remaining issues were the medical needs discount proposed by the RUD-OAG, the conservation incentive rates proposed by the MSF, and the demand side management and associated rate structures proposed by the NAWO.

To eliminate procedural uncertainty, the parties made a motion requesting specified procedural treatment of their Offer of Settlement. The ALJ certified the motion to the Commission. On April 25, 1988 the Commission issued its ORDER ESTABLISHING PROCEDURE FOR TREATMENT OF OFFER OF SETTLEMENT. That Order provided that, in the event the Commission rejected or modified the Offer of Settlement, the matter would be referred to the ALJ for further evidentiary proceedings, unless no party objected to the Commission's modification(s).

On May 27, 1988 the ALJ issued his Order Certifying Rate Design Settlement to the Commission. That Order found the Offer of Settlement to be supported by substantial record evidence, with certain reservations.

VI. PROCEEDINGS BEFORE THE COMMISSION

The ALJ closed the record on June 17, 1988 and filed his report on June 23. On July 8 the Commission heard oral argument on both that report and the Offer of Settlement. Upon review of the entire record of this proceeding the Commission makes the following Findings, Conclusions, and Order.

FINDINGS AND CONCLUSIONS

VII. JURISDICTION

The Commission has general jurisdiction over the Company under Minn. Stat. Sections 216B.01 and .02 (1986). The Commission has specific jurisdiction over rate changes under Minn. Stat. Section 216B.16 (1986).

The matter was properly referred to the Office of Administrative Hearings under Minn. Stat. Sections 14.57-14.62 (1986) and Minn. Rules, parts 1400.0200 et seq.

VIII. FURTHER ADMINISTRATIVE REVIEW

Under Minn. Rules, part 7830.4100 any petition for rehearing, reconsideration, or other post-decision relief must be filed within 20 days of the date of this Order. Such petitions must be filed with the Executive Secretary of the Commission, must specifically set forth the grounds relied upon and errors claimed, and must be served on all parties. The filing should include an original, 13 copies, and proof of service on all parties.

Adverse parties have ten days from the date of service of the petition to file answers. Answers must be filed with the Executive Secretary of the Commission and must include an original, 13 copies, and proof of service on all parties. Replies are not permitted.

The Commission, in its discretion, may grant oral argument on the petition or decide the petition without oral argument.

Under Minn. Stat. Section 216B.27, subd. 3 (1986), no Order of the Commission shall become effective while a petition for rehearing is pending or until either of the following: ten days after the petition for rehearing is denied or ten days after the Commission has announced its final determination on rehearing, unless the Commission otherwise orders.

Any petition for rehearing not granted within 20 days of filing is deemed denied. Minn. Stat. Section 216B.27, subd. 4.

IX. NORTHERN STATES POWER COMPANY

NSP is an investor-owned gas and electric utility incorporated in the state of Minnesota. It provides electric service in Minnesota to 970,000 retail customers, 844,000 of them residential. Its service area covers approximately 40,000 square miles and includes parts of Minnesota, Michigan, Wisconsin, North Dakota, and South Dakota. The Company's Minnesota service area is comprised roughly of the southern one-third of the state, and includes the Minneapolis-St. Paul metropolitan area. Most of the Company's electric revenues come from service to the metropolitan area.

This rate case involves only the Company's electric operations in the state of Minnesota.

X. SUMMARY OF PUBLIC TESTIMONY

One hundred ninety people attended the public hearings in this case, and public testimony was offered on a variety of issues.

At hearings in Winona, Mankato, Minneapolis, St. Paul, and St. Cloud, representatives of local economic development organizations appeared and presented testimony praising the Company's involvement in and contributions to their economic development efforts. Assistant Commissioner Robert De La Vega of the Minnesota Department of Energy and Economic Development also appeared and commended the Company's cooperation with his Department in attracting business and industry to the state.

At several hearings, residential customers appeared and spoke against the Company's proposal to discontinue the Conservation Rate Break. These witnesses stressed the significance of the rate break in encouraging conservation and its importance to low income and fixed income customers.

Darlene Morse, a residential customer, appeared and testified about the usage needs of people who are dependent upon electric medical equipment. She stated that her $58 monthly electric bill includes approximately $37 to operate an iron lung, an electric wheelchair, an air purifier, a humidifier, and a dehumidifier. Ms. Morse testified in favor of the medical needs discount proposed by the RUD-OAG.

A number of residential customers presented individual billing complaints. These were usually discussed after the hearing with customer service representatives from the Company and Consumer Affairs staff from the Commission.

Several customers offered general testimony that the Company's rates and costs were too high, attributing this to factors such as labor costs, executive salaries, and over-investment in generating plants. Speakers suggested that the Company invest more in conservation programs, build smaller plants to reduce its required reserve capacity, and conduct research into alternative energy sources.

Two witnesses at the Minneapolis hearing testified that the Commission should be an elected rather than an appointed body.

XI.TEST YEAR

NSP proposed a projected test year running from January 1, 1988 through December 31, 1988. No party opposed this time period. The ALJ found the proposed test year appropriate and representative of the future period during which rates would be in effect. The Commission agrees with the ALJ and will accept the test year proposed by NSP.

XII. REVENUE REQUIREMENTS STIPULATION

NSP initially requested a rate increase of $99.3 million. On February 8, 1988, the Company filed supplemental testimony reducing its request to $97.3 million. This reduction reflected the impact of NSP's early retirement program and other events occurring after the initial filing. It also included adjustments for several errors discovered in response to information requests served by the DPS and RUD-OAG.

As explained earlier the five parties who introduced most of the evidence on the financial issues, NSP, DPS, RUD-OAG, MPIRG, and MSF, submitted a stipulation reflecting agreement on all but two of these issues. The unstipulated issues related to the appropriate treatment of certain expenditures in the Company's Conservation Improvement Program Deferred Debit Account.

With one exception, no party challenged the Stipulation's resolution of any issue. The exception was NAWO's challenge to the inclusion of the new Sherco 3 plant in rate base.

The resolution of the issues set forth in the Stipulation results in a calculated revenue deficiency of $75,225,000. As part of the Stipulation, the Company agreed to seek only $75,000,000 of that amount.

The ALJ found that the Stipulation was supported by substantial evidence in all respects. He concluded that its adoption would be in the public interest and would result in just and reasonable rates. He adopted the Stipulation and the accompanying Explanation of Stipulation as his Findings of Fact, Conclusions and Recommended Order as to the stipulated issues. He recommended that the Commission adopt both documents as its final Order on those issues.

The Revenue Requirements Stipulation is not a settlement, like the Offer Of Settlement on rate design, but an agreement by the participating parties to take a joint position on certain factual and policy issues on which they had initially disagreed. In legal effect it is indistinguishable from the more common situation in which parties happen to take the same positions on certain issues. The only difference is that, in this case, the parties have formalized their agreement on the issues and have offered their unanimity as evidence of the reasonableness of their positions.

Unlike a settlement, the Stipulation reflects agreement by the parties on discrete factual and policy issues which would normally be resolved independently of one another. The reasonableness of the Stipulation's resolution of any one issue does not depend upon accepting the Stipulation's resolution of any other issue, nor does it depend upon accepting the Stipulation as a package. For these reasons, the Commission may accept parts of the Stipulation without accepting others, and without affording the parties an opportunity to change their positions on the stipulated issues. Essentially, the Stipulation is an evidentiary item, although one of great importance.

The question before the Commission, then, is not whether the Stipulation is supported by substantial evidence, but whether the positions it takes on the issues it treats are appropriate, are in the public interest, and will result in just and reasonable rates. To make this determination, the Commission must examine the Stipulation issue by issue.

XIII. RATE BASE

In its initial filing, NSP proposed an average rate base of $2,368,046,000 for the test year. In its February 8 supplemental filing, NSP revised its proposed rate base to $2,349,180,000. Most of the adjustments included in the supplemental filing were also part of the Revenue Requirements Stipulation. The test year rate base agreed to in the stipulation was $2,350,498,000.

The ALJ accepted the stipulation and adopted the resulting rate base of $2,350,498,000 in his recommendations. Since the Commission will address each of the stipulated issues individually, the Commission will use the rate base proposed in the Company's initial filing as the starting point in its determination and computation of the rate base in this proceeding. Individual rate base issues are discussed below.

A. Fuel Inventory

During the discovery process, questions raised by the DPS and RUD-OAG identified errors in the Company's calculation of average fuel inventory. NSP acknowledged the errors, corrected them, and recalculated the average fuel inventory using their most current forecast. These recalculations reduced rate base by $8,385,000. No party challenged the revised average fuel inventory, and it was included in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission accepts the revised average fuel inventory. This adjustment reduces rate base by $8,385,000.

B. Materials and Supplies

During discovery, questions raised by the DPS and RUD-OAG revealed that certain equipment had been erroneously included in NSP's repair parts calculation and that there were errors in the Company's calculation of the average materials and supplies level. NSP acknowledged these errors and recalculated the 13-month average using their most current forecast. These recalculations reduced rate base by $4,682,000. No party challenged the revised figures, and the adjustment was included in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission accepts the adjustment, which reduces rate base by $4,682,000.

C. Deferred Income Taxes - Correction

In NSP's last rate case, the Commission ordered the Company to flow back over two years amounts in its accumulated deferred tax accounts representing the difference between the old 48% tax rate and the new 46% tax rate. The Company's original filing included an adjustment to reduce the amount in the Accumulated Deferred Tax accounts which duplicated adjustments already made to the Functional Plant In-Service records for the tax flowback. The adjustment to properly reflect the impact of the tax flowback would reduce rate base by $2,206,000. NSP and DPS agreed on the correction and the adjustment was included in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission accepts the correction, which reduces rate base by $2,206,000.

D. Deferred Income Taxes - Two-Year Amortization

NSP included in its initial filing excess accumulated deferred taxes associated with the normalization of accelerated depreciation and the Comprehensive Interperiod Tax Allocation (CITA). CITA deferred taxes arise from the tax timing differences of items such as capitalized pensions, payroll taxes and property taxes.

Current tax regulations require that excess deferred taxes associated with accelerated depreciation of property be flowed back over the remaining life of the property. However, the regulations do allow the flow back of CITA deferred taxes over a shorter amortization period. The RUD-OAG recommended a two-year amortization of the $813,000 in excess CITA deferred taxes accumulated as of January 1, 1988. No party opposed the proposal, which was incorporated in the Revenue Requirements Stipulation and thereby accepted by the ALJ without discussion.

The Commission accepts the two-year amortization period. A two-year amortization period is equitable, since it is more likely than a longer period to return the funds to the customers who paid them. It is also consistent with past Commission practice in regard to returning funds to ratepayers. See, Northwestern Bell Telephone Company, Docket No. P-421/GR-82-203 (April 20, 1983); Northern States Power Company, Docket No. E-002/GR-85-558 (June 2, 1986); and Minnesota Power, Docket No. E-015/GR-87-223 (March 1, 1988).

This adjustment increases net operating income by $406,500 and increases rate base by $203,250.

E. Other Working Capital - MAPP Accounts Receivable

NSP, as the largest member of the Mid-Continent Area Power Pool (MAPP), provides most of organization's labor and manages the member billings. Members reimburse NSP quarterly for their pro rata share of costs. The DPS argued that including accounts receivable from other MAPP members in the Other Working Capital portion of the rate base is a duplication of the effect MAPP activity has on the cash working capital lead/lag study.

DPS recommended that rate base be reduced by $259,000 for MAPP labor and expense, but agreed to NSP's supplemental filing calculation of $261,000. That adjustment was included in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission agrees with the parties that the receivables from MAPP members should be removed from rate base. As in NSP's prior rate case (Docket No. E-002/GR-85-558), the Commission finds that, if it is appropriate for the Company to earn a return on this account, the return should be paid by the parties involved, not by the ratepayers. This adjustment reduces rate base by $261,000.

F. Accrued Vacations Tax Law Change

The Tax Law of 1987 disallows the inclusion of accrued vacation benefits as a current tax deduction for tax years beginning in 1988. It also provides a method for adding back to taxable income those accrued vacation benefits which have accumulated prior to December 31, 1987. The portion of accrued vacations to be included in the Company's 1988 taxable income is partially offset by accrued vacation benefits paid in January, 1988 as part of the Company's early retirement program.

There is no net income statement impact resulting from these adjustments because the increase in current income tax expense is offset by a reduction in accumulated deferred income taxes. The reduction in the accumulated deferred tax balance increases rate base by $183,000. The DPS confirmed NSP's calculations, and the adjustment was included in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission agrees with the parties that it is appropriate to adjust the rate base for the impact of the tax law changes enacted after NSP's initial filing. The Commission also agrees that the impact of accrued vacation benefits paid due to the early retirement program is properly included in the calculation of the accumulated deferred income tax reduction. The net adjustment increases rate base by $183,000.

G. St. Anthony Falls Plant

NSP included in its test year rate base the net plant balance of $428,000 associated with the St. Anthony Falls hydro plant. In November, 1987, the plant's foundation gave way, causing a collapse of the major portion of the plant structure.

The DPS proposed that the net plant balance of $428,000 be removed from test year rate base but that the test year depreciation of approximately $30,000 for the plant be allowed. This adjustment has the effect of allowing a return <u>of</u> the investment to shareholders but not a return <u>on</u> the investment. NSP and the other parties agreed to this treatment of the hydro plant investment in the Revenue Requirements Stipulation. The ALJ adopted the stipulation but did not address this specific issue.

The Commission finds that the removal of the St. Anthony Falls plant from rate base and the allowance of test year depreciation expense for the plant is reasonable and equitable, resulting in a sharing of the accident's impact between ratepayers and shareholders. This treatment is consistent with the approach the Commission has taken to losses not attributable to fault in other cases. See the treatment of excess capacity in <u>Minnesota Power</u>, Docket No. E015/GR-87-223 (March 1, 1988). The effect of removing the net plant balance for St. Anthony Falls is a rate base reduction of $428,000.

H.The Addition of Sherco 3 to Rate Base

Over half of the rate increase requested in this case is attributable to the Company's proposal to add a new generating plant, Sherco 3, to rate base. Sherco 3 is an 800 megawatt coal-fired facility in which NSP holds an approximately 59% ownership interest. The Company secured a Certificate of Need for construction of the plant in 1982, and the plant went on line in November of 1987.

Two parties advocated excluding all or part of Sherco 3 from rate base. NAWO advocated excluding the entire plant, and MSF initially advocated excluding the portion of the plant which produces electricity more expensive than the Company could currently buy from alternative sources. MSF subsequently withdrew its opposition to inclusion of the Company's entire interest in the plant, and joined in the Revenue Requirements Stipulation, which added the Company's entire interest to rate base.

1. NAWO's Position

NAWO based its opposition to rate base treatment of the plant on its contention that the Company's reliance on fossil fuel was environmentally inappropriate and should be discouraged. NAWO proposed excluding the plant from rate base, approving the entire proposed rate increase anyway, and requiring the Company to spend the entire increase on demand-side management conservation programs.

The Commission cannot accept NAWO's proposal. Minnesota law requires that utilities which prudently construct used and useful generating plants receive a return of and on those investments. Whatever the ultimate merits of NAWO's environmental concerns, it is clear that, as utility service is currently being delivered, NSP's construction of Sherco 3 cannot be characterized as inappropriate.

Sherco 3 was constructed within the budget and schedule projected in 1983. The plant has been in commercial operation since November 1987. Operation of the plant results in fuel cost savings to Minnesota ratepayers of over $11 million in the test year. These savings are projected to continue in succeeding years.

The Commission rejects NAWO's proposal to exclude the Company's interest in Sherco 3 from rate base. NAWO's proposal to require the Company to spend $75,000,000 on demand-side conservation programs will be addressed in the conservation section of this Order.

2. MSF's Earlier Position

In its initial filing, MSF advocated excluding a portion of the Company's interest in Sherco 3 on grounds that the electricity produced by the plant was more expensive than electricity the Company could buy from other utilities. MSF advocated using a formula developed by the Massachusetts Department of Public Utilities to determine how much of the plant to allow. Briefly, that formula requires calculating 1) the net present value of the utility's revenue requirement using the plant and 2) the net present value of its revenue requirement using the least expensive alternative supplier. The portion of the plant included in rate base would be based on the net present value of the second revenue requirement.

As mentioned before, MSF subsequently withdrew its support of this position and joined the parties who signed the Revenue Requirements Stipulation.

3. Commission Action

The Commission agrees with the parties that the Company's entire interest in Sherco 3 should be included in rate base. The fact that the Company can occasionally purchase power more economically than Sherco 3 can produce it is worth noting, but it is not dispositive. As the Company pointed out, these economy purchases from other utilities would not be possible without the leverage provided by its ownership of Sherco 3 and similar facilities. Sherco 3 therefore lowers its energy costs even when it is not being used.

Furthermore, as a MAPP member, NSP is obligated to maintain a specified reserve capacity, not just to meet contingencies affecting its own system, but to meet those affecting other MAPP members as well. Sherco 3 was necessary to help maintain that capacity.

Finally, it is still true, as it was when the facility's Certificate of Need was granted, that Sherco 3 is necessary to provide reliable, economical service to existing ratepayers and to fulfill the Company's duty to serve ratepayers expected to come on the system in the near term.

For these reasons, the Commission approves the inclusion of the Company's interest in Sherco 3 in rate base.

I. Sherco 3 Phase-In

The Commission, in a supplemental order to the Notice and Order For Hearing, asked that parties address the issue of possible "phase-in" of the Sherco 3 plant.

NSP, in its February, 1987 supplemental filing, argued against a phase-in from two perspectives. First, the Company suggested that a phase-in was not necessary to moderate the initial impact of Sherco 3 on rates because 1) the net impact of adding the plant is only 6.7% (using the Company's requested return on equity of 12.81%) and 2) the total six year rate increase since 1982, including the current requested increase, has been 10.3% compared to an increase in the Consumer Price Index of 22.5%.

Second, the Company argued that there would be no overrecovery of costs due to a post-test year decline in rate base because future plant additions are expected to exceed rate base reductions from Sherco 3 depreciation.

The DPS stated that five elements are normally present when state utility commissions have approved phase-in plans for major generating plants. These are:

- A rate base increase in excess of 50%
- Customer "rate shock"
- Excess capacity
- Imprudence of investment
- Plant is a high cost nuclear generating unit

DPS stated that none of the five elements were present in this case and recommended against phase-in.

The Commission is not convinced that the parties complied with the spirit of the Order requiring them to address phase-in issues. The Commission will not pursue the issue further in this proceeding, however, and will approve addition of the Company's entire interest in Sherco 3 at one time. This decision represents and implies no determination on what constitutes rate shock or under what circumstances the Commission will consider phase-in appropriate in future cases.

J. Jurisdictional Cost Allocation

NSP-Minnesota Company (NSP-MN) serves retail and wholesale customers in Minnesota, North Dakota, South Dakota; its wholly-owned subsidiary, NSP-Wisconsin Company (NSP-W) serves retail and wholesale customers in Wisconsin and Michigan. The Company must therefore have a method for allocating among jurisdictions costs incurred for the benefit of all customers.

This allocation process is complicated by the fact that NSP-MN is subject to four different regulatory authorities -- the Minnesota, North Dakota, and South Dakota Commissions, and the Federal Energy Regulatory Commission (FERC). (FERC regulates jurisdictional cost allocation between NSP-MN and NSP-W. FERC also regulates cost allocation to NSP-MN's wholesale customers within Minnesota, North Dakota and South Dakota.) Consequently, the Company uses different jurisdictional cost allocation methods in different states.

In this filing, NSP proposed to change its jurisdictional allocation method for Minnesota retail rates from the Summer and Winter Peaks (S & W) method to the 12 Monthly Coincident Peaks (12-CP) method. No other party addressed the issue. The change was incorporated in the calculations of the Revenue Requirements Stipulation and was therefore implicitly accepted by the stipulating parties and the ALJ. The Commission disallowed this same change in the last NSP electric rate case, Docket No. E-002/GR-85-558.

The S & W method is developed by computing each jurisdiction's contribution to the Company's summer and winter peak loads. The jurisdictional load contributions are weighted to reflect the relative significance of seasonal loads in determining system production plant requirements. In contrast, the demand cost allocation resulting from the 12-CP method is developed by computing each jurisdiction's contribution to all twelve monthly peak loads.

NSP cited two arguments in support of the 12-CP method. First, a significant proportion of its production plant is baseload plant, which is built to provide inexpensive energy all year. Second, a consistent cost allocation method across jurisdictions is important to prevent over- or under-recovery of costs.

The reasoning in the Commission's last rate case against the 12-CP method was as follows:

> The Commission finds that a Company providing service in more than one jurisdiction should use a consistent allocation method to distribute costs among the jurisdictions to avoid over- or under-recovery of the Company's revenue requirements. The Company's proposed allocation method has not been proposed or adopted in either the North or South Dakota retail jurisdictions. In addition, although the Company's proposed method is currently being used in the FERC jurisdiction, it is still being studied for propriety of application and may or may not be finally allowed by the FERC. Therefore, continuing the use of the Summer-Winter Peak method in this proceeding for the Minnesota jurisdiction will provide the most consistent allocation of costs among the jurisdictions and will be the best method to avoid over- or under-recovery of the total costs.
>
> NSP, E-002/GR-85-558 at 10-11.

Since NSP's last rate case, the 12-CP method has been accepted by the FERC. The Company proposed the method in North Dakota, but it was rejected in favor of a third method, the peak and average method, on March 24, 1988. The Summer and Winter Peaks method is still being used in the South Dakota jurisdiction, but NSP stated an intent to propose the 12-CP method in an upcoming rate case there.

As in the last case, the Commission believes that a consistent allocation method should be used in all of NSP's jurisdictions. At the present time, however, the other jurisdictions do not agree on an alternative to the Summer and Winter Peaks method. Under these circumstances it is premature to change from the method that has previously been found reasonable in Minnesota. The Commission will therefore use the Summer and Winter Peaks method to determine the allocation of demand-related costs to the Minnesota jurisdiction.

Staff Exhibit No. 68 shows the outcome of the cost of service study resulting from the Summer and Winter Peaks method. The Commission finds that using this method reduces the Company's filed Minnesota jurisdictional rate base by $4,192,000 and increases operating income by $288,000.

K. Rate Base Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional rate base for the test year is $2,342,665,000 as shown below (000's omitted):

Utility Plant in Service		$4,328,052	
Less: Reserve for Depreciation	1,562,325		
Net Utility Plant in Service	$2,765,727		
Accumulated Deferred Income Taxes		(590,973)	
Plant Held for Future Use	356		
Construction Work in Progress		134,047	
Working Capital:			
Cash Working Capital		(46,921)	
Materials and Supplies		44,690	
Average Fuel on Hand		36,817	
Prepayments		4,194	
Unamortized Rate Case Expense		307	
Other Rate Base		(5,579)	
TOTAL AVERAGE RATE BASE			$2,342,665

XIV. INCOME STATEMENT

A. Property Tax

The proposed rate includes a property tax increase of $26,439,000, 39% higher than the Company's property taxes during the last rate case in 1985. NSP explained that the increase was due to increased mill rates, the addition of Sherco 3 property taxes, and a 1987 property tax law that increased the assessment percentage. The Commission accepts NSP's amount for property taxes.

B. Nuclear Regulatory Commission Fee

NSP's original filing reflected a $8,424,000 increase in Nuclear Regulatory Commission (NRC) license fees for its three nuclear reactors. The Company explained that this was the expected fee amount if proposed federal legislation were enacted. NSP subsequently reduced the Minnesota Jurisdictional increase by $4,034,941, to reflect fee levels resulting from the legislation actually passed. The Commission accepts the reduction.

C. Early Retirement Program

NSP announced a voluntary early retirement program to reduce costs in late November 1987. To encourage participation in this program NSP offered its employees benefit options that increased its pension costs and related costs. NSP assumed a 35% replacement rate of retired workers. The $13,026,922 payroll savings from the early retirement program was adjusted to reflect increased pension and replacement costs, resulting in net payroll savings of $2,946,406. The related pension liabilities would increase rate base by $337,315.

NSP proposed to amortize the additional pension liability over two years. The Company contended a two year amortization period was appropriate, regardless of the timing of its next rate case because other costs would replace the amortization costs in the third year and beyond. NSP cited the loss of tax lease benefits and additional revenue requirements attributable to the Square Butte/Boswell purchase as examples of such costs.

The Commission has traditionally declined to set amortization periods on the assumption that new costs will replace the original costs and thereby protect the ratepayer from overcollection. The Commission continues to reject that approach as speculative, as inconsistent with the test year concept, and as offering insufficient protection to the ratepayer.

The Commission accepts the two-year amortization period, not for the reasons advanced by the Company, but because two years is a reasonable period over which to spread a personnel expense of this nature.

D. Sherco 3 Expenses

In its supplemental filing, NSP increased the annual operating expenses for Sherco 3 by $1,656,000. This revision reflected a lower than anticipated revenue credit from Southern Minnesota Municipal Power Association (SMMPA) due to planned outage in 1989. The Commission accepts this revision as appropriate and necessary.

E. Unbudgeted Lawsuit Claims

NSP's supplemental filing increased expenses for lawsuit claims by $1.67 million. NSP stated that the amount represents the deductible, unreimbursed portion of claims the Company expects to pay in 1988. The Commission accepts this correction as reasonable and appropriate.

F. Sherco 3 Trust Interest

NSP's original filing did not include interest income on pollution control trust funds. In subsequent discussions with DPS the Company recognized the error and included this income in its supplementary filing. The resulting increase in revenues is $698,466. The Commission accepts this adjustment to operating revenues.

G. Superfund Tax

NSP and DPS filed testimony correcting an error in the original calculation of the revenue deficiency. NSP had originally included the superfund taxes twice. The adjustment amount decreases operating expenses by $246,000. The Commission accepts this adjustment.

H. Reference Plant

NSP proposed to recover $3,384,000 in costs associated with planning its next major generating facility. These costs were primarily for conceptual design and engineering work; the Company had no particular plant, site, or construction date in mind. NSP proposed to amortize these costs over five years and to add the unamortized costs to rate base.

DPS and RUD-OAG opposed NSP's proposal on grounds that these costs are Preliminary Survey and Investigation (PS&I) costs, which are not normally added to rate base or otherwise recovered until construction begins. This was the position of the parties adopted in the Revenue Requirements Stipulation.

The Commission agrees with the parties that any recovery of these costs should await the beginning of construction and an application to transfer these funds from the Company's PS&I account to Construction Work in Progress. This is consistent with Commission practice and with the capital nature of the costs.

Deferring recovery of these costs reduces rate base by $2,505,000 and increases operating income by $677,000.

I. Economic Development

NSP proposed to include in test year expenses $770,000 for economic development. Of this amount $220,000 was for advertising and the remainder for activities such as assisting local economic development organizations and providing information to businesses which might locate or expand in NSP's service area. NSP stated that the primary purpose of its economic development program was to maintain the economic vitality of its service area, not to increase electric sales.

DPS and RUD-OAG opposed the advertising portion of NSP's economic development plan on legal grounds, citing Minn. Stat. Section 216B.16 subd. 8(c) and (d) (1986) . This section forbids recovery from ratepayers for advertising designed to promote consumption of utility service, to promote the Company's goodwill, or to improve the Company's public image. RUD-OAG also recommended disallowing recovery of one half of the remaining $550,000, because shareholders would benefit from this expenditure if it were successful.

The parties stipulated to allow one half of all expenditures, $385,000.

The Commission will disallow all these expenses. Although the importance of economic development programs is clear, the nexus between these programs and the provision of utility service is not close enough, at least in this case, to justify charging their costs to ratepayers.

Minn. Stat. Section 216B.16, subd. 6 (1986) sets forth the factors to be considered in ratemaking. These include the public's need for adequate, efficient, and reasonable service and the utility's need for sufficient revenue to enable it to supply such service, including its need to earn a fair return on its investment. The Company has not demonstrated a strong enough connection between economic development and these statutory factors to allow inclusion of these costs. Additionally, the Company's proposal does not clearly explain how economic development costs would be distributed over its geographic area.

Excluding these costs reduces test year expenses by $770,000.

J. CIP Carrying Charges

NSP proposed to assess a carrying charge on its CIP tracker account, both for the period preceding the recovery of these funds from ratepayers, and for the recovery period itself. In the Company's last rate case, the Commission had not allowed a carrying charge for the funds in the tracker account. The rationale underlying that decision was that any imbalance in the account before or during the recovery period would be inconsequential and temporary. The Minnesota Supreme Court upheld that decision in In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Service in Minnesota, 416 N.W.2d 719 (Minn. 1987).

DPS agreed with the Company's proposal. RUD-OAG advocated the disallowance of carrying charges in accordance with the policy of the last rate case. The issue was not addressed in the Revenue Requirements Stipulation.

The Commission will deviate from its previous position in light of further experience with the CIP program and will allow both carrying charges. Although it is possible that collections and expenditures will be in balance often enough to make the charge minimal, the Commission is no longer confident that this will happen. CIP costs have proven difficult to estimate with precision. Customer participation rates and project time frames have been particularly difficult to predict. It is possible that significant imbalances between collections and expenditures will occur.

Under these circumstances, equitable considerations favor allowing the Company to recover the cost of funds expended prior to collection. Similarly, it is equitable for ratepayers to receive the time value of any money overcollected for the tracker account.

The Commission will allow a one-time carrying charge of $34,827, based upon the recalculated CIP tracker balance of $857,900 and NSP's authorized rate of return; and will allow the Company to compute and assess ongoing carrying charges, to itself and to the ratepayers, to reflect imbalances between collections and expenditures in the tracker account.

K. CIP Revenue Accounting Method

In examining NSP's filing, Commission staff discovered a discrepancy between the Company's method of recording the revenue credit for its CIP tracker account and the method the Commission has recently adopted for other utilities. The Commission will require NSP to conform its recording method with the one it has recently ordered other utilities to follow. The Company did not oppose this accounting change.

The CIP tracker account consists of 2 elements - conservation expenses and the revenues collected to recover the expenses. Initially, the Company proposed recovering the necessary revenues by placing $592,127 per month in the tracker account. This monthly amount was 1/12 of the Company's projected CIP budget of $7,105,526.

The reason the Commission has rejected this method in other cases is that no provision is made for increasing or decreasing allowable CIP spending when actual sales are higher or lower than projected test year sales. Because the kWh charge paid by customers includes an amount for CIP spending, increases or decreases in sales result in increases or decreases in the amount collected by the Company; however, the amounts spent on conservation efforts remain the same.

These problems can be remedied by adopting the accounting method the Commission has recently required of other utilities. Under this method costs to be included in the tracker account are costs incurred by NSP beginning January 1, 1988. The costs in the tracker account must be separately identified by project. The offsetting amount will be collected through rates (the revenue recovery amount) to be included in the tracker beginning January 1, 1988. The revenue recovery amount is calculated by multiplying the actual sales by the recovery rate allowed in the test year. The recovery rate shall be calculated by dividing total test year sales volumes, as approved by the Commission in this case, into the allowed test year expense. This amount is termed the conservation cost recovery charge (CCRC).

Projected kWh sales for the test year are 21,841,412,000 kWh. The projected CIP budget is $7,105,526, resulting in a CCRC of $.000325.

L. Marketing Costs

NSP included in its filing $2,447,297 for marketing programs. (A portion of this amount, $770,000, was for economic development and is addressed in that section of this Order.) Certain of these programs were opposed by DPS on the grounds that they were not cost-effective. The programs and amounts are as follows:

Product Promotion	$81,291
Ultra Power Service	50,322
Customer Service and Assistance	95,489
Operating Programs Admin. & Training	210,787
Advertising Expenses	30,000

$467,889
=========

These program costs were eliminated in the Stipulation. The Commission accepts the elimination of these costs from test year expense, and finds that these programs did not demonstrate sufficient cost-effectiveness to be charged to the ratepayers.

M. In-kind Contributions

NSP stated in response to an RUD-OAG information request that it did make an in-kind charitable contribution in the form of donating employee time to the United Way Loaned Executive program. The Stipulation excludes one half ($28,000) of the costs, as required by Minn. Stat. Section 216B.16, subd. 9 (1986). The Commission accepts the exclusion of one-half of NSP's in-kind charitable contribution from test year expense.

N. Nuclear Decommissioning

On October 27, 1987 the Commission issued its Order establishing funding procedures and costs for decommissioning the Company's Monticello and Prairie Island nuclear plants. Decommissioning is not expected to occur for approximately 20 years. The size of these costs, however, and the need to collect them from the same ratepayers who receive the benefit of the plant, requires that collection procedures be established now.

DPS sought reconsideration of that Order, because the Department had not yet completed its review of NSP's decommissioning study. The Commission denied the request for reconsideration, but pointed out that the Department could again address the cost issue, if the results of its review warranted it, in the Company's forthcoming rate case, or in a later petition for Commission action.

1. Amount of Decommissioning Costs

The DPS hired a consultant, Dale Bridenbaugh, to review NSP's decommissioning study. DPS's consultant stated that NSP's $498 million cost estimate was excessive and should be revised to $399 million. Mr. Bridenbaugh's conclusions were based on a comparison of NSP's cost estimate with the results of a nationwide survey. His data suggested that the NSP cost estimate was up to 45% higher than the average of costs estimated for decommissioning other nuclear plants in his study. His analysis also criticized the estimating methods used in the NSP study. According to Mr. Bridenbaugh, NSP's study incorporates very conservative estimates of time and crew sizes. Thus, the cost estimate includes an unstated contingency factor as well as the stated contingency of 25%. For these reasons, DPS recommended removal of the 25% contingency, resulting in the revised cost estimate of $399 million. The revenue requirements stipulation incorporates the DPS's position.

The Commission will not accept the Stipulation's determination on the amount which should be set aside for decommissioning costs. The removal of the 25% contingency, as recommended by the DPS, is a significant change and the Commission is not convinced that the evidence on this issue was developed fully enough to justify changing its earlier decision. The DPS consultant obviously disagreed with the Company consultant, but the absence of rebuttal testimony and cross examination by an adverse party makes it difficult to discern and evaluate the reasons for their disagreement. Perhaps the Company consultant, if offered an opportunity for rebuttal, would present a compelling defense of his cost estimate.

Finally, a comparison of the two studies on the basis of the information available discloses no reason to favor the DPS study over the Company's. The Company's study was careful, detailed, and site-specific. The Commission examined it in a proceeding initiated solely for that purpose and accepted it after full consideration in October of 1987. The Commission will not reject it now, in the context of a proceeding in which it was one negotiable issue among many.

2. Funding Procedure

In its October Order, the Commission approved the establishment of an internal sinking fund for decommissioning. The primary reason for the Commission's choice of a wholly internal fund was that it appeared to be approximately one-third less expensive than a combined internal/external one. The Department contended in this case that recent changes in interest rates made the cost difference between the two types of funds less significant. This, combined with the increased security of an external fund, was offered as justification for a combination internal/external fund.

The Commission considered whether a higher rate of return is appropriate for estimating the return on an external fund over a period of approximately 20 years. Economic conditions, tax rates, and interest rates can be expected to fluctuate and thus alter the expected return on an external fund, depending on when the estimates are made. The Commission believes that a review of historical returns on these types of investments over a period of time would be necessary before considering a change in estimates of returns on an external fund. The Commission does not accept the DPS argument that a more optimistic estimated return on an external fund is more appropriate at this time.

3. NRC Pronouncements

Since the conclusion of hearings in the rate case, the Nuclear Regulatory Commission (NRC) has ruled that an internal fund will not be permitted to fund decommissioning. The rule will require that all decommissioning funds be provided for by: 1) prepayment; 2) an external sinking fund; or 3) an insurance method. The effective date of this new requirement will be July 27, 1990. This new requirement is different than the stipulated proposal, because it requires that a specific amount of funds be set aside using one of the methods listed above rather than a combined internal/external fund as proposed in the stipulation. The NRC will be issuing guidelines to interpret its rule within the next year, which may change the funding recommendations of the parties. Therefore the Commission concludes that any change in funding should coincide with the implementation of new funding requirements by the NRC.

The Commission will require that the Company submit information detailing its plans to comply with the NRC directives, including procedures for assuring that the external fund meets the requirements of the Internal Revenue Service (IRS) for qualified external funding. The following information must be filed, and served upon DPS and RUD-OAG, within one year of the date of this Order. The DPS and RUD-OAG shall file comments within 30 days of the Company's filing.

Filing Requirements

Time schedule for implementing a plan to establish an external fund including dates for filing requirements with NRC and IRS and depositing funds through 1993

Proposed plan and list of criteria to be used to select a trustee and investment manager

Proposed trust agreement

Proposed revenue ruling request with the IRS

Proposed reporting format to measure fund performance including benchmark comparisons

Status report and plans that the Company has to integrate its funding proposal in its other jurisdictions

Copies of Orders from NSP's other jurisdictions that address nuclear decommissioning cost estimates and funding

Explanation of the merits of establishing a non-qualified trust fund versus continuing an internal fund including costs for trust and investment management fees

Explanation and calculation of how NSP's cost estimate for decommissioning relates to the funding requirements for the NRC and IRS

O.Depreciation Study

In prefiled testimony the DPS asked the Commission to require the Company to conduct a comprehensive study of the appropriate depreciation periods for all of its facilities. The Department argued that the 33-year useful life customarily assigned to new generating facilities may not be the most appropriate depreciation period. Many plants have longer useful lives, due to retrofitting or conversion from base load to peak load facilities, and some have shorter lives.

The Department stated that the annual depreciation study required under Commission rules was not intended to be a comprehensive review of the overall reasonableness of a Company's depreciation rates, and that the Commission should require an additional, more thorough review every five years.

The Department suggested initially assigning a 33-year useful life to Sherco 3, with the understanding that this could be modified as a result of the study.

NSP initially opposed DPS's recommendation on grounds that it would require the Company to predict future technological developments to set useful lives for its property. The Company also expressed concern that the Department's approach might reflect more concern about revenue requirements than asset consumption. The Company also contended that it already used state of the art analyses and planning procedures in setting useful lives.

The DPS responded that they are not proposing that plant life be based on minimizing the revenue requirement. DPS believes an improved modeling effort by NSP would improve the estimation of plant life and therefore the asset consumption. Subsequently, the Company stated it was not opposed to investigating, jointly with the DPS, its depreciation lives and estimating procedures, and whether alternative methodologies merited investigation.

The Commission will require the Company and the Department to conduct such an investigation and to report its results to the Commission within eight months of the date of this Order.

P. Rate Case Expenses

NSP has included in this filing $1,039,260 in regulatory expenses for the test year, with $367,000 attributed to this rate case. The Company proposed to amortize its rate case expenses over two years.

The Commission will not approve a two-year amortization period. In recent years most utilities have not filed rate cases biennially. Should NSP's next filing follow this pattern, the Company would have overcollected rate case expenses. The Commission will therefore provide a three-year amortization period. This adjustment reduces operating expenses by $61,000 and increases rate base by $31,000.

The Commission is also concerned about the lack of specificity in the Company's descriptions of both its rate case and general regulatory expenses. Both expenses are substantially higher than they were in the Company's 1985 general rate case filing. The Company has explained that this is due in part to unintentional underreporting of its 1985 rate case expenses. NSP stated that it actually spent $339,000 on the case, not the $190,000 it reported.

Nevertheless, to ensure that the Company's projected rate case expenses are reasonably accurate, the Commission will require the Company to file a detailed itemization of rate case expenses within six months of the date of this Order. The Company should also include in that filing a more detailed itemization by year of its 1987 and 1988 general regulatory expenses. The detail of the information shall identify legal, consulting, administrative and federal and state agency billings. NSP should present such expenses with more specificity in future rate cases.

Q. Operating Income Statement Summary

Based on the above findings, the Commission concludes that the appropriate Minnesota jurisdictional operating income for the test year is $183,057,000 as shown below (000's omitted):

Operating Revenues:			
Retail Electric Revenues		$1,037,896	
Service Connection, Late Payment and Returned Check Revenue		5,146	
Total Retail Revenues		$1,043,042	
Other Operating Revenues		141,377	
Gross Earnings Taxes		16,775	
Total Operating Revenues		$1,201,194	
Operating Expenses:			
Production	$ 505,238		
Transmission		23,520	
Distribution		71,081	
Customer Accounts and Sales		27,334	
Customer Service and Information	6,493		
Administration and General	79,425		
Provision for Depreciation and Amortization		145,114	
Taxes:			
Real Estate and Property		94,292	
Gross Earnings			16,775
State and Federal Income		44,087	
Deferred Income		$ 10,407	
Total Operating Expenses		$1,023,766	
Operating Income Before AFUDC		$ 177,428	
AFUDC			5,629
Net Operating Income		$ 183,057	

XV. CONSERVATION

A. Conservation Improvement Plan

Minn. Stat. 216B.16, subd. 1 (1986) requires that a public utility's notice of change in rates include "an energy conservation improvement plan pursuant to section 216B.241." NSP submitted a conservation plan in Volume III(B), Financial Information, Section N, of NSP's direct testimony (Exh. NSP 70).

The DPS stated that while NSP's plan is generally appropriate it failed to quantify conservation objectives and recommended that the Company be required to include this information. NSP did not respond to this issue.

The Commission agrees with the DPS. Quantifying conservation goals will require the Company to realistically assess its market for potential conservation savings and will require it to consider conservation as a low-cost alternative to expensive capacity building investments. Through Minn. Stat. 216B.241 (1986), the Legislature has encouraged utilities to become increasingly involved in conservation. The analysis and information being required of NSP will benefit not only its own ratepayers, but ratepayers throughout Minnesota. The Commission will order NSP to file this information within 30 days of the issue date of this Order.

B. Good Cents Program

At issue is whether NSP should be allowed to recover $734,400 in pre-1987 expenditures for the Good Cents Home Program. The Good Cents Program is designed to develop energy efficiency standards. NSP representatives examine construction plans with builders and homeowners and then recommend cost-effective energy improvements.
The DPS argued that NSP failed to seek Commission approval prior to starting the program. The DPS stated that NSP's Good Cents Program had been rejected by the Commission as a marketing program before it was approved in March 5, 1987 following substantial modifications. The DPS contended that the issue is not whether the Company acted in good faith, but whether the Company had Commission approval to implement this program.

NSP requested recovery of the program costs prior to 1985. NSP claimed that the Commission has never ordered that prudent CIP costs incurred prior to program approval cannot be recovered once the program is approved. NSP stated that it is reasonable to expect some expenditures would be made before a program is approved.

NSP argued that it began the program in response to the Sherco 3 Stipulation, that all expenditures were made in good faith and that the changes made to the original program were not substantial. NSP stated that if Good Cents expenses were denied, ratepayers would receive the benefits of the start-up costs (including the license to run the program and staff training) for nothing.

The ALJ agreed with the DPS.

The Commission recognizes that the evaluation of conservation projects and programs has evolved since the early 1980's. When the Good Cents Program began, there was some confusion as to its objectives. NSP and other parties worked together to bring it into conformance with Commission conservation standards. The Commission believes that the modifications to the program did improve its cost-effectiveness, but did not alter greatly its implementation. The Commission finds that ratepayers have benefitted from this program and concludes that NSP may recover $734,400 in pre-1987 expenditures for it.

C. Past CIP General Administrative and Regulatory Expenses

At issue is whether NSP should be allowed to recover $843,400 in General Administrative and Regulatory (A&R) expenses for the October 1, 1985 - December 31, 1987 Conservation Improvement Program (CIP) period.

The DPS stated that NSP is seeking to recover through the tracker account expenses which were never presented to or approved by the Commission in the annual CIP process. The DPS argued that NSP provided no evidence that actual expenditures for administrative activities for 1986 and 1987 were not incorporated into each conservation program. The DPS also stated that NSP indicated that the general administrative account receives expenses from both conservation and operating programs. The DPS questioned the reasonableness of the amount sought by NSP since the amount is significantly higher than average NSP CIP administrative expenditures. Finally, the DPS noted that NSP had not produced any evidence to show these aberrations are reasonable.

NSP stated that the DPS offered no evidence that there was double recovery of the A&R costs.

The ALJ recommended allowing $284,616 because he found it reasonable to assume that some A&R monies were spent by NSP. This figure was computed by totalling approved or uncontested comparable amounts allocated for 1985 and 1988. The ALJ recommended disallowing any higher amount because NSP provided no evidence to identify A&R costs that support all CIP programs, as distinct from A&R costs that support operating programs.

The Commission accepts the DPS recommendation to disallow the recovery of $843,400 in General Administrative and Regulatory (A&R) expenses for the October 1, 1985 - December 31, 1987 CIP period. The total cost of CIP programs is an important factor in determining the overall cost-effectiveness of CIP; therefore the Commission must be presented with all expenses at the time of each CIP filing. The Commission finds that NSP has never before presented these administrative costs for approval. The Commission's CIP evaluation process affords companies opportunity to account for their CIP expenses. The Commission also finds there was nothing in the record to indicate whether or not operating program administrative costs had been included in the conservation tracker account. Operating programs are not part of CIP and costs incurred by operating programs should not be included in the conservation tracker account.

The Commission will disallow the recovery of $843,400 in A&R expenses for the October 1, 1985 - December 31, 1987 CIP period.
The Commission will require NSP to clearly identify costs for operating programs and separate them from the conservation tracker account in future rate case filings.

D. Summary of Tracker Account Recommendations

Amount in the Conservation Tracker Account

	NSP	DPS	ALJ
Amount not in dispute	$ 123,500	123,500	123,500
Good Cents Program	734,400	0	0
A&R expenses 1986-7	843,400	0	284,616
Total	$1,701,300	123,500	408,616

Both the DPS and the ALJ recommended that the final approved amount left in the account should be surcharged to any interim rate refund. The DPS argued that this is a good method because it would clean-up the account, making it easy to inspect in future rate proceedings. The Commission agrees with the DPS and the ALJ. The Commission finds that the final approved amount is $857,900, which consists of the amount not in dispute and the Good Cents Program amount.

E. Development and Financing of Electrical Efficiency Programs

1. Pollution Abatement Credit Rule

NAWO saw a need for crediting utilities for pollution abatement which benefits society, including the ratepayers. According to NAWO, this would make efficiency improvement investments much more cost-effective from the utility's standpoint.

The Commission will not adopt a pollution abatement credit at this time. The Commission feels that a state-wide perspective on this issue may provide a coordinated approach to any pollution abatement credit policy. There are a number of forums available for investigating this issue. The State Planning Agency has convened a Task Force to consider future legislation on utility conservation issues. The Commission serves on that Task Force. Also, the Commission notes that a Least Cost Planning approach to conservation, if approved by the Legislature, will involve the review of the present regulatory system and any disincentives it may create for demand-side planning. The Commission will continue to research the issue of pollution abatement credits in its ongoing analysis of conservation opportunities and incentives.

2. Disallowance of Sherco 3 and Approval of $75 Million Increase

NAWO argued that the Commission has the opportunity to move toward a balanced supply-side/demand-side management of a utility by granting NSP its requested $75 million test year rate increase, rejecting the inclusion of Sherco 3 in the rate base and providing the Company with a rate of return on equity that is appropriately above the stipulated 11.7%.

The ALJ concluded that it is inappropriate to deduct $470,000,000 from the Company's rate base for disallowance of the Sherco 3 plant. $45.5 million of the stipulated revenue increase is raised by applying the stipulated overall rate of return to the $470,000,000 increase in rate base for Sherco 3. NAWO would allow collection of $75 million even without Sherco 3, leading to a rate of return on equity of about 17% (compared with 11.7%) with an overall rate of return of 12.1% (compared with 9.68%). The ALJ found NAWO's proposal unreasonable, contrary to state law and not supported by the record. NSP and the DPS drew similar conclusions.

Minn. Stat. Section 216B.16, subd. 6 (1986) lists factors that the Commission must consider in determining just and reasonable rates for public utilities. The Commission must consider the public's need for adequate, efficient, and reasonable service. The Commission must also consider the utility's need for revenue sufficient to meet the cost of furnishing service, including adequate provision for depreciation of utility property which is used and useful in rendering service to the public and an opportunity to earn a fair and reasonable return upon its investment in such property.

The Commission finds that NSP acquired a Certificate of Need for Sherco 3 pursuant to Minn. Stat. Section 216B.243 (1986) and that the plant is used and useful in providing utility service to NSP's customers. The Commission concludes that the requirements of Minn. Stat. Section 216B.16, subd. 6 (1986) have been met and that NSP is allowed to include Sherco 3 in rate base and to earn a fair and reasonable return on its investment in it. The Commission will reject NAWO's proposal to exclude Sherco 3 from rate base.

3. Monthly Efficiency Clause Adjustment

NAWO argued for a monthly efficiency clause to adjust rates upward according to the amount of energy saved. This clause would compensate for company revenue losses. NAWO argued that consumers' bills can remain stable, or even be reduced (due to lower consumption), to reflect the Company's reduced fixed and operating expenses. NAWO stated that electric bills would become more of a function of services rendered, than of kilowatt hours consumed. Adjustable rates would protect the Company's revenue requirements. NAWO noted that the principle behind such rate adjustments is already being employed in the form of fuel adjustment clauses. The ALJ considered an efficiency clause inappropriate in this proceeding.

The Commission finds that, without the implementation of extensive cost-effective conservation, an efficiency clause would have a negative impact on customers. For ratepayers' bills to remain stable or be decreased, the higher rate required by the efficiency clause would need to be offset by a decrease in the number of kWh used. Therefore the Commission agrees with the ALJ and rejects the efficiency clause proposal in this proceeding.

4. NAWO Study Proposal

NAWO stated that NSP's present limited programs and NSP's lack of information regarding sector-by-sector cost-effective end-use efficiency improvement potential do not reflect the nature of costs of extensive, well-developed programs. NAWO proposed that it be funded with $25,000 to $1 million to identify specific end-use efficiency improvement potential and specific extensive programs. The ALJ agreed with the DPS that Conservation Improvement Program proceedings or a generic, industry-wide advisory board would be more appropriate forums for addressing this issue than a rate case proceeding.

The Commission questions whether a rate case is an appropriate forum for approving a private individual's conservation proposals. The Commission is aware that information on conservation opportunities is available from other sources as well as NAWO. The annual Conservation Improvement Program process affords all interested persons an opportunity to present conservation proposals. The Commission will reject NAWO's study proposal.

XVI. RATE OF RETURN

A. Return on Common Equity

The issue before the Commission is the fair and reasonable return on equity to be authorized for NSP.

NSP witness Pender performed a Discounted Cash Flow (DCF) analysis on NSP data and a comparable group of utilities and an equity risk premium analysis. He estimated the cost of common equity to be 13.77%, 12.93%, and 13.87%, respectively from these studies. As a matter of policy, NSP requested a return on common equity of 12.81%, the same return authorized by the Commission in the Company's last electric case, NSP, E-002/GR-85-558.

RUD-OAG witness Marcus relied primarily on a DCF analysis of NSP data, with a DCF on a benchmark group of 28 electric utilities as a check. He calculated a cost of equity of 11.60% and 11.95%, respectively from these analyses. Dr. Marcus found a reasonable range of common equity returns for NSP of 11.60 to 11.80%, recommending the lower end of the range, 11.60%, due to NSP's strong financial condition.

MSF witness Zapp relied on a DCF analysis of NSP data. He determined the cost of equity for NSP to be 11.77% to 11.80%. Dr. Zapp recommended allowing a return on common equity for NSP of 11.80%.

The parties to the Stipulation agreed to a rate of return on common equity for NSP of 11.70%, based on the testimony of RUD-OAG witness Marcus and MSF witness Zapp. The ALJ found the proposed 11.70% return on equity reasonable and appropriate.

In reaching a decision on the appropriate cost of common equity, the Commission must act within the scope of both its enabling legislation and the strictures of reviewing judicial bodies. Two United States Supreme Court cases provide general guidelines for rate of return decisions:

(a) The allowed rate of return should be comparable to that generally being made on investments and other business undertakings which are attended by corresponding risks and uncertainties.

(b) The return should be sufficient to enable the utility to maintain its financial integrity.

(c) The return should be sufficient to attract new capital on reasonable terms.

See Bluefield Water Works & Improvement Co. v. P.S.C., 262 U.S. 679 (1923), and FPC v. Hope Natural Gas Co., 320 U.S. 591 (1944).

The Minnesota Supreme Court, in Minnesota Power & Light Company v. Minnesota Public Utilities Commission, 302 N.W.2d 5 (1980) at 9, held that the establishment of a rate of return involves a factual determination which the court will review under the substantial evidence standard.

The Commission has reviewed the testimony of all parties, the Stipulation and supporting explanation of the parties, and the recommendation of the ALJ. The Commission will draw its conclusions from the evidence presented and its own expertise, and will set forth the factual basis for its decision.

The Commission agrees with the parties and the ALJ that an 11.70% rate of return on common equity for NSP is reasonable and supported by the record of this proceeding. This return is in the middle of the range of the recommendations made in prefiled testimony by Dr. Marcus and Dr. Zapp.

Dr. Marcus and Dr. Zapp both relied primarily on DCF analyses of NSP data. Dr. Marcus also used a DCF analysis on a benchmark group of electric utilities as a check on his results. Under the DCF method, the cost of equity is inferred by observing past and present market data and making reasoned judgments of investor expectations for the future. The DCF analyst generally makes use of a formula in which the required rate of return on equity is equal to the sum of the dividend yield and the growth rate expected by investors. The Commission finds that the DCF method is firmly grounded in financial theory and has been relied on by the Commission in nearly every rate case proceeding since 1978. The Commission also finds it reasonable to place primary weight on the results of a direct DCF analysis of data for NSP since its stock is actively traded in the market and, thus, its price, dividends, and past performance are directly observable.

Dr. Zapp used an average of twelve monthly dividend yields for NSP to calculate his adjusted dividend yield of 6.37% for NSP. Dr. Marcus also looked at twelve monthly dividend yields, but averaged this result with the most recent three month yields to derive his somewhat higher adjusted yield of 6.60% for NSP. The Commission finds that the period over which the dividend yield is measured should reflect current conditions and be representative of investor expectations, while being long enough to smooth the effect of any temporary market fluctuations. Both witnesses expressed similar goals in their choice of dividend yield periods. The Commission finds a dividend yield in the range of 6.37% to 6.60% reasonable for NSP.

Dr. Marcus concluded that prospective growth in book value and estimates of growth by institutional investment analysts were the most reliable indicators of growth expected by investors in NSP. He determined that a 5.00% growth rate for NSP was indicated. Dr. Zapp examined earnings per share growth for NSP over the last five years and also looked at forecasted growth by investment analysts to derive his recommended growth rate of 5.40%. The Commission finds it reasonable to examine historical growth rates along with information about current and future conditions when estimating investors' future growth expectations. Both witnesses did so. The Commission finds a growth rate in the range of 5.00% to 5.40% reasonable for NSP.

Dr. Zapp recommended a return on equity for NSP of 11.80%, based on his analysis. Dr. Marcus determined a cost of equity from his direct analysis of NSP data of 11.60%. Based on its discussion above, the Commission finds that a cost of equity in the range of 11.60% to 11.80% from Dr. Marcus' and Dr. Zapp's direct analyses of NSP data is reasonable.

Dr. Marcus also looked at a benchmark group of 28 electric utilities as a check on his direct NSP analysis and determined a cost of equity of 11.95% for the group. Because the benchmark group was financially weaker than NSP, he concluded that a somewhat lower return on equity, at the low end of the reasonable range of 11.60% to 11.80%, should be granted to NSP. The Commission finds it appropriate to check the reasonableness of the results of a direct DCF analysis of a company's data by looking at a group of companies with reasonably similar risk characteristics, as Dr. Marcus did. The Commission finds that the results of Dr. Marcus' DCF analysis of the benchmark group confirm the reasonableness of a cost of equity for NSP in the range of 11.60% to 11.80%.

Therefore, the Commission finds a return on equity in the range of 11.60% to 11.80% should be granted to NSP based on the record in this proceeding. The parties to the Stipulation adopted the midpoint of this range, 11.70%, as the appropriate return on equity to use in setting rates in this proceeding. Based on the DCF analyses of Dr. Marcus and Dr. Zapp, the results from Dr. Marcus' benchmark group, and the trend in financial market conditions, the Commission concludes that the reasonable return on equity for NSP is 11.70%. This return on equity is supported by substantial evidence, is fair and reasonable, and will allow NSP to attract capital on reasonable terms and maintain its financial integrity.

B. Capital Structure

The issue before the Commission is the appropriate percentage levels of debt, preferred stock, and common equity to be included in NSP's capital structure for ratemaking purposes for determining the overall cost of capital.

NSP proposed a capital structure containing 2.74% short-term debt, 40.96% long-term debt, 11.06% preferred stock, and 45.25% common equity. It is an estimate of NSP's actual average capital structure for the test year for its consolidated operations, adjusted to exclude equity investments in non-utility subsidiaries and to treat part of its Refuse Derived Fuel investment as debt instead of equity.

RUD-OAG witness Marcus and MSF witness Zapp stated that the proposed capital structure was reasonable for ratemaking purposes in this proceeding, and it was adopted by the parties in the Stipulation. The ALJ found this capital structure to be appropriate.

As part of its ultimate obligation to set just and reasonable rates for utility service, the Commission is charged with determining the most reasonable capital structure for NSP for ratemaking purposes. In making that determination, the Commission must balance the needs of ratepayers for economy and investors for safety.

The effective cost of debt for a company is lower than its cost of equity because the interest rates required by debt-holders are generally less than the return required by stockholders, and because interest expense is tax deductible. Therefore, all other things equal, a lower proportion of equity in the capital structure will result in lower rates for customers. However, beyond some point too much debt may lead to increased financial risk for a company due to greater uncertainty that earnings will cover fixed cost obligations. If the Commission finds that a utility has not achieved a reasonable balance, causing ratepayers to pay an unreasonably high cost of capital, the Commission will adjust the capital structure for ratemaking purposes to put it within a reasonable range.

In the Company's most recent prior electric and gas rate cases, NSP, E-002/GR-85-558 and NSP, G-002/GR-86-160, the Commission found that NSP's proposed equity ratios of 45.99% and 45.45%, respectively, were excessive and placed an unreasonable burden on ratepayers. The Commission found that use of a 45.00% equity ratio for ratemaking purposes properly balanced the interests of ratepayers with fairness to NSP. Furthermore, the Commission put the Company on notice that it would continue to use a hypothetical capital structure for ratemaking purposes unless it was clearly shown that NSP's proposed equity levels were reasonable.

All parties presenting testimony on this issue found NSP's proposed capital structure to be reasonable. Dr. Zapp disagreed with NSP's stated equity ratio objective of 45.00% to 50.00%. He argued that a capital structure with more than 45.00% equity would impose unnecessary cost on ratepayers, but felt that the proposed 45.25% equity ratio was within reason. No party introduced evidence that an equity ratio of less than 45.00% would be appropriate at this time for NSP. The Commission observes that if a 45.00% equity ratio were substituted for the 45.25% equity ratio in the capital structure proposed by the parties, the same proposed 9.68% overall return would result and NSP's revenue requirement would not be materially affected in this proceeding.

Thus, the Commission finds that ratepayers will not be burdened by unreasonable rates due to an excessive equity ratio if the capital structure proposed in the Stipulation is used in computing NSP's revenue requirement. This proposed capital structure has been adjusted to exclude certain non-utility investments from common equity. The Commission finds the capital structure proposed in the Stipulation fairly balances the interests of ratepayers and shareholders, and will allow NSP to attract needed capital on reasonable terms.

Based on the discussion above, the Commission concludes that the capital structure proposed by the parties in the Stipulation is reasonable for calculating the overall rate of return on rate base for NSP in this proceeding. However, the Commission is not endorsing NSP's stated capital structure goals and will adjust the Company's capital structure for ratemaking purposes in any future proceeding if NSP fails to clearly show by competent evidence that its proposed equity ratio is reasonable.

C. Cost of Debt and Preferred Stock

The Commission will next determine the appropriate cost rates for the debt and preferred stock components of the capital structure.

No party disputed NSP's proposed cost rates of 6.89% for short-term debt, 8.45% for long-term debt, and 6.74% for preferred stock, and they were adopted in the Stipulation. The ALJ found these cost rates to be appropriate.

The Commission agrees that the cost rates for short-term debt, long-term debt, and preferred stock proposed by the parties and adopted by the ALJ are reasonable and appropriate. The Commission finds that these cost rates reasonably reflect the costs expected to prevail for NSP during the test year.

D. Overall Rate of Return

Based upon its decisions above, the Commission concludes that the overall rate of return on rate base for NSP in the test year is 9.68%, as shown below:

	Amount ($000)	Percent	Cost	Weighted Cost
Short-term Debt	$ 81,476	2.73%	6.89%	0.19%
Long-term Debt	1,219,863	40.96%	8.45%	3.46%
Preferred Stock	329,452	11.06%	6.74%	0.74%
Common Equity	1,347,619	45.25%	11.70%	5.29%
Total	$2,978,410	100.00%		9.68%

XVII. REVENUE DEFICIENCY

The above Commission findings and conclusions result in a Minnesota jurisdictional gross revenue deficiency of $73,184,000, determined as shown below (000's omitted):

Rate Base			$2,342,665
Rate of Return			9.68%
Required Operating Income	$ 226,770		
Test Year Net Operating Income	183,057		
Operating Income Deficiency		$ 43,713	
Revenue Conversion Factor	1.674201		
Gross Revenue Deficiency		$ 73,184	

In the test year income statement, the Commission found that Minnesota retail revenue from sales of electricity at present rates is $1,043,042,000. Adding the gross revenue deficiency of $73,184,000 to this amount results in total authorized revenue from Minnesota retail customers of $1,116,226,000.

XVIII. RATE DESIGN

A. Offer of Settlement

The parties presented an offer of settlement that proposed to settle some, but not all, rate design issues. The settlement was originally signed by a limited number of parties on March 31, 1988. All parties had agreed to the settlement by April 8, 1988. NSP Ex. 28, 28A, 28B, and 28C.

Three issues were excepted from the rate design settlement: a special rate discount for customers who have medical needs which require greater electric usage proposed by the RUD-OAG, conservation incentives for residential rates proposed by the MSF, and demand side management and associated rate structures proposed by the NAWO. The NAWO proposal is discussed in the Conservation section of this Order. All other rate design issues are discussed below.

The Commission approves the rate design settlement. The rate design included in the settlement is just and reasonable. Additionally, it is not unreasonably preferential, prejudicial or discriminatory.

The settlement's tables show a $75 million dollar revenue deficiency. However, the parties intended that the settlement's inter- and intra-class rate relationships apply to the Commission-determined revenue deficiency. The Commission agrees. In its compliance filing, the Company shall present the settlement rate design, adjusted to recover no more than the Commission-approved revenue requirement.

The Commission recognizes that the settlement is a compromise and does not necessarily represent the positions the parties would have taken had they fully litigated the case. In the settlement, the parties reserved the right to take positions contrary to the settlement in future proceedings. The Commission makes an analogous reservation. Accepting the settlement does not obligate the Commission to make the same or similar decisions in future proceedings.

B. Class Cost of Service Studies

NSP presented a fully-allocated, stratified, embedded class cost of service study. It used the methods adopted by the Commission in NSP's last four electric general rate proceedings. The stratification process classifies some production plant costs as energy-related and some as demand-related. This recognizes that baseload plants cost more to build, but provide lower-cost energy. In contrast, peaking plants cost less to build but are more expensive to operate and thus generate higher-cost electricity.

NSP proposed one change from the class cost of service study (CCOSS) adopted by the Commission in NSP's last electric rate case, Docket No. E-002/GR-85-558. That change was to assign conservation costs on a program-by-program basis rather than on a system-wide basis. That is, costs were assigned to specific customer classes containing eligible participants in the conservation programs.

The Department supported the NSP cost study except for the one change from the last rate case. The DPS proposed a different change in the way conservation costs are allocated.

The DPS determined that 65% of all conservation costs were demand-related and 35% were energy-related. The DPS then allocated both types of costs on a system-wide basis by using demand and energy allocators. The DPS advanced this method as recognizing the purpose of conservation programs: to reduce system-wide energy costs and defer or displace the need for future capacity (demand-related) costs.

Both NSP and the Department submitted marginal class cost of service studies for informational purposes. Neither party asked the Commission to base inter-class revenue responsibilities on marginal costs. Therefore, the Commission will take no action on the marginal class cost of service studies.

The RUD-OAG advocated two changes to NSP's CCOSS. The first was a proposal to allocate conservation costs on a system-wide basis, 50% as demand-related and 50% as energy-related. This method was approved by the Commission in NSP's last rate case, Docket No. E-002/GR-85-558. This method recognizes that conservation programs provide system-wide benefits, some demand-related and some energy-related.

The second RUD-OAG-recommended change to NSP's CCOSS involved NSP's assumed minimum distribution system. In estimating the costs of its minimum system, NSP hypothesized a system of sufficient capacity to serve customers of 1 to 1.5 kilowatts. The RUD-OAG argued that NSP's approach overstates customer-related costs because its minimum size is too large for residential customers and the remaining demand costs are allocated based on total relative class demands. According to the RUD-OAG, the relative class demands should have been recalculated to give a credit for the demand costs assigned to the customer cost category.

Champion International opposed NSP's use of the stratification method. Under NSP's method, over 73% of investment in production plant is allocated to the customer classes based on energy consumption. Champion asserted that NSP's approach fails to recognize why production-related investments and associated fixed costs are incurred by NSP. Instead, NSP should have classified 100% of its production plant as demand-related. Furthermore, plant so classified should have been allocated on class coincident peak. According to Champion, to do otherwise conflicts with cost causation and NSP's corporate goals. In Champion's view, NSP's annual peak load determines the amount of capacity that NSP must have.

The St. Paul Area Chamber of Commerce (Chamber) asserted that NSP's CCOSS assigned more production costs to the high-load-factor customer classes than is appropriate, disadvantaging the primary voltage and transmission voltage commercial and industrial classes. Those classes have higher load factors than the residential class and the secondary voltage commercial and industrial customers. The Chamber asserted that NSP's cost study overstated the costs and understated the revenues that should have been allocated to the primary and transmission voltage customers.

The Metalcasters asserted that NSP's study overstated the cost of serving interruptible customers. The Metalcasters identified four errors in NSP's cost study. First, the Company understated interruptible kilowatt-hour sales. Second, the Company incorrectly allocated energy-related production plant costs to interruptible customers in the same manner that such costs were allocated to firm customers. Third, the Company incorrectly assigned winter peaking plant costs to the interruptible subclass. Finally, the Company used seasonal weights to allocate energy-related production plant costs.

For purposes of the settlement, the parties based their proposed rate design on NSP's cost study as amended by the RUD-OAG and the DPS for the allocation of conservation costs. The ALJ accepted the settlement rate design.

The Commission finds that the additional cost of baseload production plant is incurred because of the relatively cheap energy that the plant provides. The stratification process acknowledges this and classifies the additional cost as energy-related. Thus, stratification represents how the costs are caused. The Commission therefore adopts the stratification method advocated by NSP, the DPS and the RUD-OAG.

The Commission notes that the RUD-OAG and the DPS advocated different methods of allocating conservation costs. The Commission cannot accept both methods.

In NSP's last rate case, Docket No. E-002/GR-85-558, the Commission classified conservation costs as 50% demand-related and 50% energy-related, finding that conservation programs provide system-wide benefits. Further, conservation programs are designed to reduce both energy consumption and future investment in capacity. Therefore, a portion of the costs should be allocated to energy and a portion to demand. The Commission found it is appropriate to split the conservation program cost equally between energy and demand.

In this case, the Commission finds that there is insufficient evidence to support a change in the method of allocating conservation costs. Therefore, the Commission adopts the RUD-OAG-proposed method of allocating conservation costs.

The Commission rejects the coincident peak method advocated by Champion. It is inconsistent with the stratification method adopted above. Furthermore, the Commission finds insufficient evidence to support the modifications proposed by either the Chamber or Metalcasters. Their proposals represent significant departures from the stratification approach which has consistently been adopted by the Commission. Finally, the Commission rejects the RUD-OAG's criticism of NSP's minimum system. Since the RUD-OAG's minimum-system critique was neither quantified nor based on Commission precedent, there is insufficient information to support it.

For this case, the Commission adopts the NSP embedded CCOSS, as amended by the RUD-OAG for the allocation of conservation costs. The Commission notes that the parties entered into a rate design settlement of this case. Therefore, the CCOSS issues were not fully litigated by the parties. For this reason, the Commission may adopt different CCOSS methods in future cases.

C. Allocation of Revenue Responsibility to Customer Classes

The following table shows the parties' revenue allocation based on NSP's originally-proposed revenue requirement:

<u>Revenue Increase by Class</u>
($99.7 Million or 9.5% Overall Increase)

Class	NSP/DPS/ Metalcasters	RUD-OAG	Champion	Chamber
Res.	10.5%	9.5%	12.2%	12.2%
C&I	9.1		8.2	8.1
PubAuth	10.1		14.4	10.1
St&Area	3.4		0.3	3.4

NSP essentially proposed an across-the-board allocation of the revenue increase. NSP modified the allocation slightly to bring the classes closer to NSP's view of cost. The DPS and the Metalcasters agreed with the NSP class revenue allocation.

The RUD-OAG proposed an average increase for the residential class based on its recommended changes to the cost study. Also, the RUD-OAG observed that in the last electric rate case, Docket No. E-002/GR-85-558, the residential class received an average increase based on similar inter-class cost relationships.

The Chamber proposed that residential and C&I (commercial and industrial) rates be increased at a ratio of 1.5 to 1. This was based on the Chamber's view of the corrections needed to NSP's cost study. The Chamber further proposed that the rates of each C&I category be increased equally.

Champion, based on its cost study, recommended that inter-class subsidies be reduced by one-half with the constraint that no class receive a revenue decrease.

In the rate design settlement, the parties agreed to retain the existing inter-class revenue allocations. This was based on the general proposal of the RUD-OAG. The parties agreed to be consistent with the Commission's method of setting revenue allocations in NSP's last electric rate case, Docket No. E-002/GR-85-558.

The parties made two exceptions to this. The first exception was the apportionment to the street and area lighting class, whose rates are closer to cost than other classes' rates. The parties proposed a 2.6% for this class to keep its rates at cost.

The second exception to the inter-class rate design adopted in the last case involved the addition of Sherco 3. The added costs of Sherco 3 are fixed costs, as compared to fuel costs, which are variable. Moreover, the purpose of this case, according to the parties, is to recover increases in non-fuel costs, because fuel costs are handled separately through the fuel adjustment process.
Thus, the parties agreed that the increase should be allocated based on each class's proportionate non-fuel revenues. In that manner, the existing inter-class rate design would be retained. The ALJ recommended approval of the rate design settlement and, therefore, this method of class revenue allocation.

The Commission agrees that the relative class responsibilities found appropriate in NSP, E-002/GR-85-558, continue to result in an equitable distribution of the revenue increase. The Commission further agrees with the parties that the increase should be based on non-fuel costs. Finally, a 2.6% increase for the street and area lighting class is appropriate. This increase will keep that class's rates at or near cost. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

D. Intra-Class Rate Design

1. Residential Class

a. Medical Needs Discount

The RUD-OAG proposed a rate discount for residential customers who have high electric usage resulting from medical conditions. A 25% price discount would apply to all usage up to 1000 kWh monthly. NSP argued that the proposed discount is arbitrary, inefficient, not cost-based, not required by statute, and has been previously rejected.

The RUD-OAG proposed that persons who require a power wheelchair, a hemodialysis machine or respiratory equipment qualify for a rate discount. The RUD-OAG chose 25% as the medically necessary discount level because the Conservation Rate Break (CRB) now provides approximately a 25% discount. The 1000 kWh threshold was chosen for the discount by adding an assumed medically-related usage of 600 kWh plus the 400 kWh covered by the CRB. The maximum monthly discount would be $15. To qualify, a customer would have to present a signed statement from a doctor certifying a qualifying condition. The RUD-OAG proposed that a task force study whether other medical needs should be included.

NSP countered that a similar proposal was advanced by the United Handicapped Federation (UHF) in NSP's 1980 and 1981 rates cases. In both cases, the Commission rejected it as not being supported by enough information. NSP further argued that the proposal is not cost-based and is not required by the legislature. NSP conceded that the RUD-OAG has simplified a rather complex UHF proposal. However, NSP argued that the RUD-OAG still had not provided enough information about its cost and scope.

The Company said that its rates already are affordable. NSP argued that rate design is not an efficient way of solving social problems and expressed concern that a reduction in electric bills might trigger a reduction in other welfare benefits.

NSP predicted an enforcement problem if handicapped people leave a household without notifying NSP that the household has become ineligible. Finally, NSP stated that the RUD-OAG left too many questions to be solved by a task force while still recommending that the discount be implemented before the task force accomplished its work. According to NSP, the RUD-OAG failed to meet its burden of proof.

The RUD-OAG replied that NSP should support this concept because NSP supports handicapped organizations through its charitable contributions. Since the discount would not affect the residential class's contribution to embedded cost, the RUD-OAG asserted that the discount does not contradict the concept of cost-based rates.

The RUD-OAG offered its proposal as simpler to administer and more closely linked to cost than the UHF proposals previously rejected. The RUD-OAG stated that if the discount would cause ineligibility for another welfare program, the customer could refuse the discount. The RUD-OAG maintained that the Commission's legislative function confers the authority to order this discount without express approval from the legislature.

The ALJ found that the record does not establish a basis for estimating how many of NSP's customers would qualify for the medical needs discount. For that reason the ALJ recommended that the medical needs discount not be adopted.

The Commission wants individuals who use large amounts of electricity for medical reasons to have affordable electricity. However, an NSP rate proceeding is not the proper forum to address the electricity needs of those individuals. The Commission believes that the legislature is the proper forum to address this issue.

Thus, the Commission reaches the same conclusion as the ALJ, but not for the same reason. The RUD-OAG had argued that the Commission has authority to approve the medical needs discount. The question is not one of authority. The question is, what level of government can best address this issue. The medical need for electricity exists state-wide, while the Commission's ratemaking authority extends only to certain utilities, and does not cover the entire state.

Furthermore, the legislature can better address the relationship of the medical needs discount to social programs offered by other state agencies. The legislature also could address the question of whether the discount should be extended to other medical needs. The Commission believes that the legislature should address this issue and will not approve the medical needs discount.

b. Inverted Rates

The Metropolitan Senior Federation (MSF) proposed inverted rates to encourage residential conservation. Customers who consume more electricity would pay higher rates during the summer, NSP's peak season. The MSF cited a tariff of Philadelphia Electric Company as evidence that this proposal is reasonable.

NSP and the DPS opposed the MSF's proposal. The DPS opposed inverted rates because they are not cost based, that is, NSP's cost of providing electricity does not vary with an individual customer's consumption. Regardless of their consumption levels, individual customers impose high capacity and energy costs if they consume during peak periods.

NSP criticized the MSF for not providing enough evidence to support its proposals. NSP argued that there is no evidence that current rate design provides an incorrect economic conservation signal. Similarly, there is no evidence that a different rate design would tap an untapped well of potential conservation. Finally, NSP cited a lack of evidence that the proposal is fair and easy to administer.

The MSF argued that its inverted rate proposal would cause minimum rate shock and would recover class revenues equitably from cost-causers. Additionally, this would eliminate the winter end-step, which the MSF argues is a conservation disincentive. The MSF justified adverse rate impacts by the potential amelioration of acid rain and the greenhouse effect. Space-heating customers should be offered time-of-day or interruptible rates to cushion the impact on their rates, according to the MSF.

The ALJ found that adoption of the inverted rate would result in a large, but unquantified, increase in the bills of some residential customers. Furthermore, regardless of consumption level, individual customers impose high capacity and energy costs if they consume during peak periods. He concluded that the record contains insufficient evidence to support adoption of the inverted rate proposal.

In its exceptions to the ALJ's report, the MSF provided additional quantification of the impact on residential customers.

The Commission adopts the DPS and NSP position that the proposed inverted rate would not be cost-based. In addition, it would have a significant bill impact on some customers, especially space heating customers and farmers. Therefore, the Commission rejects the MSF's inverted rate design proposal.

c. Conservation Incentive Rates Study

The MSF proposed a study to compare current weather-normalized consumption with a base level of consumption. Rates could then be designed to ensure that customers whose energy use increased would pay a higher rate and those whose energy use decreased would pay a lower rate.

According to the MSF, such rates would reduce acid rain and the greenhouse effect. The MSF estimated that 10-25% of residential consumption could be saved with good energy management. The savings to customers would be more than $30 million per year, providing an incentive for customers at all consumption levels.

NSP replied that the MSF's numbers are pure conjecture. Furthermore, such a rate design would require a substantial amount of consumption and weather history. NSP argued that it would be unfair and infeasible.

The MSF felt that the rate design should be studied because of its great potential, but conceded that a substantial amount of data would be needed to administer the rates.

The ALJ stated that the rate design could reward customers who wait until after the rate took effect at the expense of customers who are currently saving energy.

The Commission agrees with NSP and the ALJ. The MSF's energy savings estimates are conjecture rather than reliable facts. Even if the savings estimates were reliable, the rate design would be extremely difficult to administer fairly. The Commission believes that the ALJ has raised a fundamental problem with this concept. The Commission will not approve the use of ratepayer funds to study it.

d. Winter End-Step

NSP proposed to increase the winter end-step discount from the current $0.45 to $1.28 per kWh. NSP offered three reasons for this. First, NSP said that space heating customers impose lower costs than other customers. This difference is 0.21¢/kWh. Second, since the customer charge does not recover all customer-related costs, NSP in effect proposed to recover some of the remaining customer-related costs through the first block of the winter rate. Finally, NSP said that space heating customers would suffer a severe billing impact if the winter end-step were eliminated.

The RUD-OAG recommended retaining the end-step discount at its current 0.45¢/kWh level. NSP's cost study overstates the amount of costs identified as customer costs, according to the RUD-OAG. Therefore, NSP's proposal to recover customer charges in the first block is not justifiable. Furthermore, if the recovery of customer costs through the energy rate did justify the winter end-step, then NSP should have a summer end-step, too. However, NSP is correct about the billing impacts, so the end-step should be retained at its current level, according to the RUD-OAG.

The DPS position was that declining block rates send inappropriate price signals. Costs vary by season, time-of-day and temperature, but not by a customer's cumulative consumption. The DPS argued that the Company has proposed to eliminate the conservation rate break (CRB). If the Commission adopts the Company's CRB proposal, eliminating the winter end-step would mitigate the billing impact on small customers.

The parties settled on a 50% reduction in the winter end-step discount. The new end-step discount would become 0.23 cent under their proposal. The parties explained that this balances the Commission's interest in discouraging declining block rates with avoiding rate shock which may have resulted from the total elimination of the winter end-step and acknowledges the cost savings attributable to serving large residential loads.

The Commission adopts the settlement position on the winter end-step discount. The evidence in this case shows that a discount of 0.23 cent will bring the rate closer to cost. A 0.23 cent discount would strike an appropriate balance between cost considerations and the Commission's desire for moderate billing impacts. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

e. Conservation Rate Break (CRB)

NSP proposed to eliminate the CRB, asserting that it was not a cost-effective conservation effort, nor an appropriate means of assisting low-income customers. NSP believes that the CRB depends on life style. Apartment dwellers and customers without major electric appliances are more likely to receive the CRB, regardless of whether they actually have conserved energy. An NSP survey showed that a small fraction of CRB recipients actually conserved energy with the CRB in mind.

The MSF proposed supplementing the CRB with an inverted rate design. If the CRB is retained as a lifeline rate, it should be subject to an income test. That is, only qualifying low income customers should receive the CRB.

The RUD-OAG argued for retaining the CRB. It believed NSP's survey was flawed. The RUD-OAG felt that the CRB had not been properly marketed by NSP. The RUD-OAG was concerned about the billing impact of eliminating the CRB, especially on low-income customers.

The parties settled on retaining the CRB but at a reduced level, $3.50 per month, rather than the current $4.00 per month. The parties believe that maintaining a significant CRB prevents rate shock to low-use customers. The conservation and lifeline effects of the CRB would be retained at a reduced level. The 50-cent reduction in the CRB would lessen the rate impact on larger customers of reducing the winter end-step discount by 50 percent.

The Commission finds that the CRB should be retained at a reduced level of $3.50 per month. Retaining the CRB will prevent rate shock to low-use customers. Reducing the CRB will moderate the rate impact on larger customers of decreasing the winter end-step discount. Thus, the $3.50 level balances the needs of smaller customers with those of larger customers. The Commission wishes to encourage conservation, but believes that there may be other rate designs that encourage conservation better than the CRB does. In future rate cases, the Commission will be open to other proposals for conservation rate design. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

f. Customer Charge

The current residential customer charge is $4.00, having been raised from $3.50 in the last electric rate case. NSP originally proposed no increase in the customer charge in this proceeding because it proposed eliminating the CRB. Without the removal of the CRB, NSP stated that it would have proposed that the customer charge be increased closer to the customer-related cost of $11.03 per month.

The DPS agreed with NSP that the customer charge should not be increased if the CRB were eliminated. However, the DPS recommended a $4.50 customer charge if the CRB were retained.

The RUD-OAG requested that the customer charge remain at $4.00 since the principal cause of the rate case is the addition of Sherco 3, which does not increase customer-related costs.

The parties settled on a 50-cent increase in the customer charge to $4.50 per month. This is slightly more than would occur under an across-the-board increase. Thus, it moves the rate closer to cost. Finally, recovering proportionally greater revenues from small users moderates the rate impact of reducing the winter end-step by 50%. For these reasons, the Commission adopts a residential customer charge of $4.50 per month. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

g. Conclusion

As discussed above, the Commission approves changes in the winter end-step, the CRB and the residential customer charge. These changes were considered as a package. Each of these changes differs in its impact on small customers compared with large customers. Each change was tempered by a consideration of the effects the other changes would have. The Commission believes that further evaluation of the CRB and the winter end-step will be necessary in future cases.

2. The Farm Class

No party disputed NSP's recommendation to eliminate the farm class and make it part of the residential class. The usage and cost characteristics of the two classes are similar. This results in a lower rate increase for the farm class. The Commission adopts this recommendation.

3. Small General Service Rate Design

Under present rates, small general service energy rates are the same as residential energy rates without the winter end-step. NSP proposed that small general service rates increase by 5.79 percent overall, which was less than the 10.54 percent proposed increase for the residential class. NSP proposed to increase the general service customer charge to $6.00 from $5.45. The remainder of the increase would be in the energy charge, which would then be less than the residential energy charge.

The DPS disagreed with NSP's proposal to charge different energy rates to residential and small general service customers. The DPS cost study showed little difference between the two classes.

The Chamber asserted that the small general service load factor is 20% higher than that of the residential class. Therefore, the cost of service per kWh is lower and should be reflected in the rate.

The parties agreed to adopt the DPS proposal, which was to maintain the existing relationship between the small general service and residential rates. Only the customer charge and the winter end-step would differ. (Small general service would continue to have no winter end-step.) The parties agreed that the customer charge should be increased to $6.60 per month to achieve the goal of giving each commercial and industrial class the same percentage increase net of fuel costs.

The Commission agrees with the DPS. The energy-related cost difference between residential and small general service customers is small. Therefore, the current relationship between their energy charges should be maintained. The small general service customer charge should be increased to give the small general service class the same increase net of fuel costs as the other commercial and industrial classes. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

4. General Service and General Service Time of Day Rates

NSP proposed two refinements to its general service rates. First, NSP proposed reducing the customer charge to reflect customer-related costs for small commercial customers. Second, NSP proposed setting the energy and demand charges such that one-third of the proposed revenue increase would be in the energy charge and two-thirds would be in the demand charge. According to NSP, this would produce an appropriate balance of billing impacts on customers across the range of load factors. This also reflected NSP's position that demand-related costs have increased more than other costs.

The DPS testified that the demand charge seasonal differential should be increased to $2.25 per kilowatt (kW). The DPS represented this as a moderate move toward a cost-based differential.

The Chamber disagreed with NSP's proposal to reduce the general service customer charge. The Chamber asserted that even the smallest demand-metered customers pay a customer charge that is below cost, so the charge should not be reduced.

Consistent with its cost study, Champion said that fixed costs should be recovered through demand charges and variable costs through energy charges.

The parties agreed to the DPS proposal to set the seasonal differential at $2.25 per kW. The energy charges would be reduced from NSP's initial proposal in proportion to the reduction in revenues from those originally proposed. This balances billing impacts with the increase in demand-related costs. The customer charge would remain at its present level as recommended by the Chamber and Champion. General service time of day customers would receive an additional charge of $6.00 per month to reflect the special costs imposed by time of day service.

The Commission agrees that the settlement position reflects a balancing of billing impacts with the increase in demand-related costs and adopts it for that reason. The Commission approves a seasonal demand charge differential of $2.25 per kW. The energy charges will be reduced from NSP's initial proposal in proportion to the reduction in revenues from those originally proposed. The Commission approves an additional charge of $6.00 per month for general service time of day customers. This increase is based on the special costs imposed by time of day service and is reasonable. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

5. Interruptible Customer Charges

NSP proposed identical customer charges for firm and interruptible customers. NSP's intent was to make interruptible service more flexible and attractive to potential customers, to reduce complexity in customer billing and rate administration, and to increase customer understanding.

The DPS recommended that the customer charge for interruptible customers be raised by $11 per month to reflect higher costs. The Chamber supported the DPS proposal.

The settlement incorporates the DPS proposal to increase interruptible customer charges by $11 per month. As discussed above, time of day customer charges would be an additional $6 per month.

The Commission finds that the settlement reflects a proper move toward cost without an unduly large billing impact or undue complexity. The Commission approves a customer charge increase for interruptible customers of $11 per month. An additional $6 per month charge for time of day customers is discussed above. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

6. Energy-Controlled Service Energy Rate

NSP proposed an overall increase of 11.36% for this class. At secondary voltages, NSP proposed a 13.4% increase to the off-peak demand charge and a 17.0% increase to the off-peak energy charge. NSP proposed that the customer charge be equal to the general service time of day customer charge ($26 per month).

The DPS testified that NSP's proposed peak/off-peak energy charge ratio of 1.1 is too far below the cost ratio of 1.35. The DPS advocated a ratio of 1.25, closer to cost than NSP's ratio.

The parties settled on the DPS position. The Commission adopts it. The DPS position is based on cost and does not cause severe billing impacts. The customer charge for this rate will be $40.60 per month in order to include the additional $11.00 per month because it is interruptible and the additional $6.00 per month because it is a time of day service, as discussed above. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

7. Peak Controlled and Peak Controlled Time of Day Demand Charges

NSP proposed that the differences between the demand charges applied to general service and peak controlled customers be raised from $2.25/kW to $2.75/kW. NSP asserted that there is no direct connection between the long-run marginal capacity cost and the appropriate discount for interruptible load.

The Metalcasters proposed that the demand charge differential be raised to $3.25/kW. Metalcasters felt that NSP's cost study was flawed, as discussed earlier in this Order. Metalcasters asserted that the value of interruptible loads exceeds $5.00/kW.

The parties agreed to NSP's position. The Commission has adopted the NSP cost study for the reasons given above. Therefore, it does not accept the Metalcasters argument about the demand charge differential. The Commission adopts NSP's position that the demand charge differential should be increased to $2.75/kW. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

8. Peak Interruptible Large General Service Rate

NSP proposed to cancel this rate, arguing that it is sufficiently close to the peak-controlled service rate that the remaining eight customers could be transferred without unreasonable billing impacts. This proposal was originally opposed by the Metalcasters. Later, the Metalcasters agreed not to oppose cancellation of this rate. No other party opposed it. Therefore, the Commission approves the cancellation of this rate.

9. Maintenance Power Tariff

The DPS recommended that NSP propose a maintenance power tariff within nine months of the Commission's Order in this case. Maintenance power refers to the power provided by the utility during periods of scheduled outages needed to perform routine maintenance on an independent generator's units. The maintenance power tariff would be distinguished from the standby power tariff, which would then apply to unscheduled outages by an independent generator. The parties agreed that NSP should propose a maintenance power tariff within nine months.

The Commission agrees that there is an important distinction between maintenance power and standby power. The Company should have rates for both so that independent generators will perceive the proper costs. The Commission will order NSP to file a maintenance power tariff proposal within nine months of the date of this Order.

10. Standby Power Rate

The DPS suggested two refinements to NSP's method of calculating this rate. First, the Company would include the costs of demand-metered secondary-voltage customers, which had been excluded. Second, the Company would rely on availability factors, rather than reserve margins, in determining the rate. The parties agreed that NSP will adopt these refinements when it next proposes a change in the rate or in its next rate case.

The Commission agrees that the costs of demand-metered secondary-voltage customers should be considered in calculating this rate. The evidence suggests that availability factors may be more appropriate than reserve margins in determining the rate. The Commission will order NSP to consider availability factors and demand-metered secondary-voltage customers when it next proposes a change in this rate or in its next rate case, whichever is sooner.

11. Competitive Service Rider

NSP proposed to add a competitive service rider to prepare for increased competition. Under this rider, the level of demand and energy charges would be negotiated for the individual customer. The DPS, District Heating, and the Chamber variously opposed this as either discriminatory, unworkable, or not in the public interest. NSP withdrew its proposal. Therefore, the issue is moot and the Commission will take no action on it at this time.

12. Other Sales to Public Authorities

NSP proposed to increase the small municipal pumping service rate by more than the overall percentage increase requested in this case to move this rate closer to the small general service rate. NSP wanted to reduce the difference in the energy charges by one half.

The City of St. Paul, the Board of Water Commissioners of the City of St. Paul, and the Suburban Rate Authority argued that municipal pumping customers impose fewer costs than general service or small general service customers and, therefore, NSP's proposal for a greater-than-overall increase should be rejected.

In the proposed settlement, the parties agreed that the increase for this class should be consistent with the overall increase (net of fuel costs). Thus the energy charge and customer charge would be kept equal to those of the general service class. The demand charge would be set to collect the desired overall increase and to maintain the seasonal differential of the general service rate design.

The Commission adopts the settlement position. The rate design principles discussed above should govern. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

13. Lighting Class

The parties agreed that the lighting class should be limited to a 2.6% increase to keep its rates at cost. This is lower than the overall increase because this class's rates are closer to cost than other classes' rates are.

The Commission finds that this is consistent with the cost study adopted in this case. It also does not impose an immoderate burden on the other classes and the Commission will adopt the settlement position. As with all other settled rate design issues, the Commission is not obligated to adopt this or a similar position in future proceedings.

E. Fuel Adjustment Clause True-up

NSP proposed a true-up to assure that rates track fuel costs more precisely.

The DPS asserted that NSP's proposal runs counter to the Company's efforts to address competitive pressures facing the Company. Since the proposal would not affect test year revenue requirements, it would not give greater protection to ratepayers or shareholders. The DPS defined the purpose of the fuel clause as to avoid rate cases due solely to increased fuel costs, but not to track fuel costs precisely. Finally, the true-up is not necessarily perfectly accurate, according to the DPS.

NSP agreed to withdraw its proposal from the rate case. Therefore, the issue is moot and the Commission will take no action on it at this time.

ORDER

1. Northern States Power Company is entitled to increased gross annual revenues of $73,184,000 to produce total annual operating revenues of $1,116,226,000 from Minnesota retail customers for annual periods beginning January 1, 1988.

2. The rate design settlement is approved.

3. Within 30 days of the service date of this Order, NSP shall file with the Commission for its review and approval, and serve on all parties in this proceeding, revised schedules of rates and charges reflecting the revenue requirement for annual periods beginning January 1, 1988, and the rate design decisions contained herein. NSP shall include proposed customer notices explaining the final rates. Parties shall have 15 days to comment.

4. Within 30 days of the service date of this Order, the Company shall file with the Commission for its review and approval, and serve upon all parties in this proceeding, a proposed plan for refunding to all customers with interest the revenue collected during the interim rate period in excess of the amount authorized herein. The refund may be reduced by the CIP tracker balance with carrying charges. Parties shall have 15 days to comment.

5. Within 30 days of the service date of this order, NSP shall file a quantitative statement of the reduction in electric consumption NSP intends to achieve during the time period covered by its conservation plan. In NSP's next electric rate case, it shall include this information in its conservation plan.

6. Within six months of the date of this Order, NSP shall file additional detail of actual rate case expenses and general regulatory expenses for 1987 and 1988. The detail of the information shall identify legal, consulting, administrative, and federal and state agency billings. Similar detail shall be filed with the Company's next electric general rate case.

7. Within eight months of the date of this Order, NSP shall file a report on depreciation lives and estimating procedures. The report shall be prepared in consultation with the DPS.

8. Within nine months of the service date of this Order, NSP shall file with the Commission for its review and approval, and serve on all parties in this proceeding, a maintenance power tariff. NSP shall work with the DPS in developing the proposed tariff.

9. When NSP next proposes a change in the standby power rate, or in its next electric general rate proceeding, whichever is sooner, it shall consider availability factors and demand-metered secondary-voltage customers in calculating the standby power rate.

10. Within one year of the service date of this Order, NSP shall file information detailing its plan to comply with the NRC directives on nuclear decommissioning and necessary procedures to assure that the external fund meets the requirements of the Internal Revenue Service for a qualified external fund. The required information is detailed in the Nuclear Decommissioning section of this Order. NSP shall file this information with the Commission, the DPS, and the RUD-OAG. The DPS and the RUD-OAG shall file comments within 30 days of the Company's filing.

11. This Order shall become effective immediately.

BY ORDER OF THE COMMISSION

Mary Ellen Hennen
Executive Secretary

(S E A L)